3Rs for Power And Demand

Dynamic monitoring and decision systems maximize energy resources.

By Marija Ilic

The operations and planning rules for integrating variable resources aren't the same across the electric power industry in the United States at present. Opinions are somewhat divided about what these should be, as well as the assessments of potential benefits and costs. In order to support sustainable deployment of variable resources at value, it's critical to identify major sources of potential problems and to proactively design and implement a systematic framework for managing their unique characteristics as reliably and efficiently as possible. It would be possible to efficiently and reliably integrate relatively large-scale wind capacity in the existing electric power grids provided that this is done in coordination with responsive demand. However, in order for this to happen, it's critically important to manage industry risk in qualitatively different ways than is done at present.

In particular, the rules, rights and responsibilities (the 3Rs) need to be established to provide incentives to all for sharing the right information and for self-managing their resources dynamically in the face of seemingly large variability. Short-, mid- and long-term physical and financial risks must be aligned and distributed among many power producers, end users, aggregators, delivery providers, system operators and system-wide coordinators. A multi-layered, multi-directional and interactive IT architecture that dynamically supports the aligning of physical and financial risks according to the 3Rs is the key to distributing risks among states, utilities, emerging aggregators, and individual producers and end users.

> Needs and resources can be accurately forecast only when producers and responsive demand provide binding self-commitments.

An implementation comprising a physical power grid with its resources, IT-enabled communications and embedded decision-making intelligence would become a much talked-about smart grid capable of managing distributed risk at value. Instead of planning and operating for meeting system-wide reliability criteria centered around grid integrity, load-serving entities would be required to provide information about the short- and long-term characteristics of their customers and resources. Moreover, they would have to specify their willingness to respond to system conditions at the value pre-specified by themselves. Much complex decision making and autonomy would be left to the system users and this would reduce the need for complex decisions by the system operators.

A proof-of-concept implementation example of large-scale wind power dispatch in coordination with price responsive demand is shown for illustrative purposes on an IEEE RTS Test System *(see Figure 1)*.

Distributed Dynamic Risk Management

Today's basic rules for integrating variable resources in operations and system planning aren't the same in all parts of the U.S. electric power grid. The differences concern scheduling priorities (*i.e.,* must-run plants in the MISO, self-scheduling in PJM), through settlement methods (*i.e.,* real-time prices without being required to bid in MISO; real-time price settlements with required day-ahead bidding in PJM), and charges for additional system support to compensate for highly deviating from forecast (*i.e.,* not subject to uplift in MISO, or subject to uplift charges in PJM). In addition, at the investment stage, wind power plants are almost universally entitled to clean credit tax breaks of some sort.

While it might appear at first look that it's not necessary for the 3Rs to specify the mechanisms for implementing highly technical functions, such as short-term unit commitment, economic dispatch, mid- and long-term forward capacity and energy commitments in the changing industry, the details of this being done have great implications. Financial bilateral deals are viewed, by and large, as being sufficient for ensuring long-term energy and capacity, and as separable from engineering planning and operating rules; their implementa-

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tion is considered better left to the system operators and engineers. However, industry experience to date has shown that long-term bilateral contracts fall short of being utilized to their capacity when scheduling is done by the system operators whose prime objective is system reliability without taking risks.

One possible way to bridge this gap between contracted capacity and actual energy use would be to design and implement regulatory rules that support managing physical and financial risks in qualitatively different ways than is being done today. Moreover, given the highly technical system operations, and the temporal and spatial complexities, aligning financial and physical risks probably isn't achievable without on-line information about what's available with high certainty, by whom and to whom.[1] Aligning financial and physical risks would require the 3Rs to specify the minimal information exchange necessary among resources, aggregators, system operators and regional coordinators. This exchange is essential for ensuring just-in-time (JIT) and just-in-place (JIP) utilization of existing resources, as well as systematic commitments to ensure mid- and long-term sustainable electricity services. In addition, the information has to be both technical (*i.e.,* regarding quantity, time and location) and financial (*i.e.,* willingness to pay or get paid), and must be binding.

Rethinking the way risk is managed would considerably impact predictions concerning long-term energy resources, which fundamentally are based on coarse estimates of available capacity and, at best, on long-term available average energy (*see Reference 1*). These estimates, as a rule, don't take into account the possible enhanced utilization of existing resources by more dynamic JIT and JIP predictions and adjustments. Instead, they're based on current (N-1) reliability criteria, which require a large reserve to meet the long-term system

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peak-load forecast even during worst-case forced equipment outages. A quick assessment of the actual load and the planned load shows that the actual load is generally much lower except during some very short infrequent time intervals. This means that the probability of utilizing full capacity is very low, and the resources are, by and large, under-utilized. This discrepancy has huge effects on what gets built and operated relative to what would be needed if the burden of forecast were distributed across all market participants, and if power producers and responsive demand were given the opportunity to manage their own objectives under uncertainties by offering binding self-committing supply and demand bids, respectively.

Groups of resources are in a much better position to provide the information about what is possible to produce and when, by internalizing the cost of their own inter-temporal characteristics and uncertainties at risk levels they are comfortable with. If this is done and communicated to the system operators, most of the aggregate self-committed power, energy and capacity would become predictable and dispatchable with surprisingly high accuracy. This, in turn, would eliminate concerns regarding the volatility of variable resources. Having both conventional and new resources specify their ability to supply, and having users specify their willingness to adjust, would increase the number of possible providers and would, ultimately, reduce gaming to a significant degree.

This distributed risk-management concept contrasts sharply with today's practice, in which the overall physical and financial risks associated with both long- and short-term uncertainties are borne by the customers, often after the fact. Moreover, today the effects of inter-temporal constraints are spread across all participants and there is simply no way to value different technologies based on the rate at which they could respond. This overall situation has resulted in both a lack of incentives to utilize resources efficiently—because those causing inefficiencies don't pay for it—and also in a lack of interest by the customers to participate more pro-actively in decisions related to their electricity services; the signals to price-responsive demand aren't strong enough to reflect the true value of their participation.[2] This also has led to the inability of specialized technologies to recover their costs. The system operator at present doesn't have different rules for compensating expensive storage than it does for paying the combined-cycle power plant. This, in turn, requires subsidies to support the deployment of new technologies, such as storage. Moreover, electricity market derivatives aren't sufficiently diverse technologies to be differentiated

FIG. 1 GENERATION MIX FOR IEEE RTS TEST SYSTEM

Unit Type	Min Gen	Max Gen	Marginal Cost	Ramping Rate
Oil	0 MW	551 MW	200$/MWh	200 MW/10min
Coal	50 Mw	874 MW	50$/MWh	150 MW/10min
Nuclear	100 MW	400 MW	10$/MWh	10 MW/10min
Natural Gas	10 MW	400 MW	130$/MWh	200 MW/10min
Wind	0 MW	2,400 MW	0$/MWh	150 MW/10min

Source: IEEE Task Force, *See Reference 3.*

according to their rates of response.

The magnitude of these problems likely will grow as plans are made for deploying more varied resources—wind, PHEVs, fuel cells, batteries, and solar—and the gaps will increase between what customers want, what producers want and what is sustainable and good for the society as a whole. And, consequently, the problem of missing investment money will remain. While these gaps have existed in the past, they are becoming pronounced because of the unusually high uncertainties brought about by industry restructuring, environmental objectives and the influx of novel technologies. These range across regulatory, physical and financial uncertainties.

While some of these uncertainties are harder to manage, it's possible to do significantly better with relatively modest regulatory and technical design of 3Rs for future energy systems. For example, using such possible simple 3Rs in support of large-scale wind integration and responsive demand yields quantifiable enhancements in system performance.

3Rs for Wind Power And Demand

Consider the problem of integrating large-scale wind capacity in operations without creating reliability problems. The first question is how to treat wind power. If it's considered as a negative inelastic load, this right away results in higher volatility than today's system load and requires even larger stand-by and capacity reserves than at present. NERC (N-1) reliability criteria aren't explicit, at this time, about how to treat wind.

One possible design of the 3Rs would be to treat wind power producers the same way as all other power producers. The burden of predicting their output would be left to producers. They also would have the choice of bidding as a portfolio with power producers or with responsive demand to better manage correlated inter-temporal risks. They would

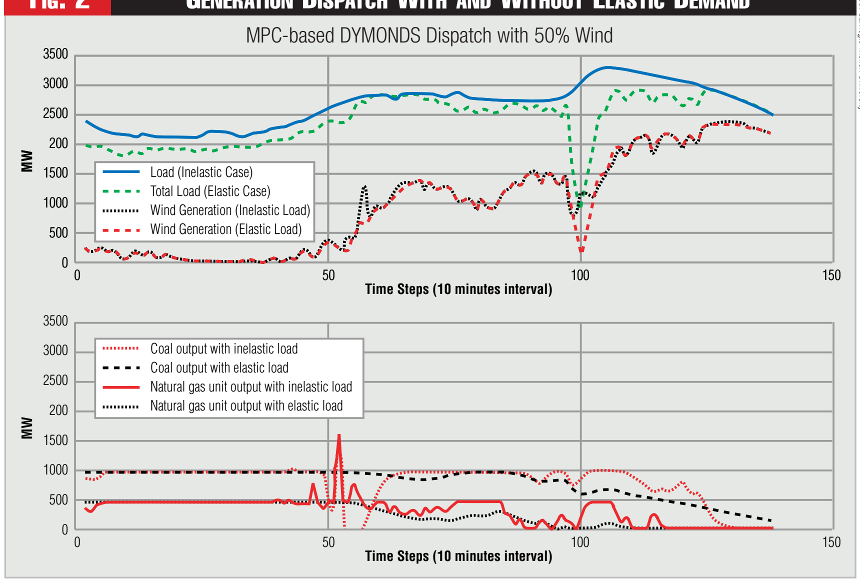
> Internalizing the risk by those creating it would make the responsibilities much better understood.

bid the same way as fully dispatchable power plants bid now. However, their bids, once cleared, would be binding, the same as for other more conventional resources. Seen by the system operator, they would be fully dispatchable except for very fast relatively small fluctuations.[3] This is technologically feasible.

In addition, the 3Rs design would treat consumers the same way as any other market participants. They would have to define their demand characteristics and would be obliged to meet them. The end users interested in responding to the system conditions would bid their demand functions after internalizing their inter-temporal constraints and willingness to risk not being served. These bids will be binding, once cleared. The demand-side providers also would quickly find out that bidding as a portfolio with other power producers or users might be highly beneficial for them.[4]

The design of the 3Rs for the system operators would require them to collect the self-committing bids from the resources participating, clear the bids without worrying about the dynamic inter-temporal constraints, and make the prices and quantities cleared publicly available. The ISOs would have to design the 3Rs for their ancillary service markets to account for deviations of power committed from the actual outputs. There should be two major new functions for the system operators to perform: 1) manage mid- and long-term self-committed resources reliably within their own area, and, as a part of this process, begin to provide coordinated mid-and long-term cleared prices;[5] and 2) become an integral part of much larger regional and inter-regional coordinated and reliable clearing of available resources. Notably, today's SCADA has no on-line coordinating information exchange across the control areas or regions; this is known as "the seams problem." In the next generation, SCADA should have this coordinating layer based on the minimal coordination of binding information exchange. This wouldn't require any change of present ownerships, just carefully engineered 3Rs for coordinated information

FIG. 2 GENERATION DISPATCH WITH AND WITHOUT ELASTIC DEMAND



Source: Carnegie-Mellon University

exchange in support of physical, financial and environmental risk management at value (*see Reference 6*).

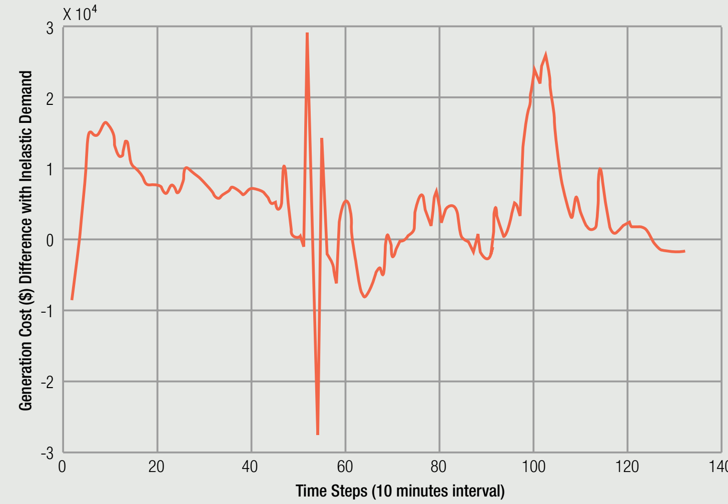
>50 Percent Wind

Recent work (*see Reference 2*) has shown that it's possible to have a rather straightforward self-commitment by power producers and responsive demand, which when cleared using today's security-constrained economic dispatch (SCED), enables a large integration of wind capacity without violating transmission constraints. In essence, the 3Rs would require each power producer to look ahead over the time horizon relevant for its own technology and optimize its own objectives.

Based on this optimization, each power producer would create and submit supply functions that are no longer inter-temporally constrained. Similarly, responsive demand would optimize its own objectives and offer demand functions that are no longer inter-temporally constrained. The system operator then would run its dispatch every hour, every 15 minutes, or even every five minutes, and selects the bids (supply and demand) according to the system-wide criteria, which in this case are the criteria of social welfare.[6]

Take for example, the results of such a 3R-based self-commitment day-ahead dispatch for the IEEE RTS test system with more than 50-percent wind capacity *(see Figures 2-5)*. *Figure 1* displays the generation mix with wind generation replacing the generation mix originally given for this system in *Reference 3*. Shown in *Figure 2* is the result of the generation dispatch with large-scale wind power. The system load (solid blue line) is smoother than the total load (green dotted line) when the demand is elastic. The difference between the two shows how much the demand was adjusted to accommodate wind while observing the ramping rates of all power plants. It shows that both coal and gas generation produced significantly less with elastic demand. As wind output suddenly drops, so does the elastic demand.[7]

FIG. 3 COST DIFFERENCE BETWEEN MPC-BASED DISPATCH FOR 50% WIND CASE



Zero baseline = generation cost in 50-percent wind scenario with elastic demand.

Source: Carnegie Mellon University

It's interesting to observe that relatively little demand elasticity made possible large wind power utilization (*see Figure 4*) and, consequently, a reduction in polluting coal and gas power outputs. Also, *Figure 3* plots the total generation cost difference with and without elastic demand. Finally, *Figure 5* shows the strong negative correlation between the demand change and demand elasticity.[8] Further extensions of this work are needed to ensure feasible voltage support. It is widely recognized that significant efficiency and reliability enhancements, everything else being equal, would be brought about by systematic voltage management as real power is dispatched (*see References 4 and 5*). Even blackouts could be prevented this way (*see Reference 6*).

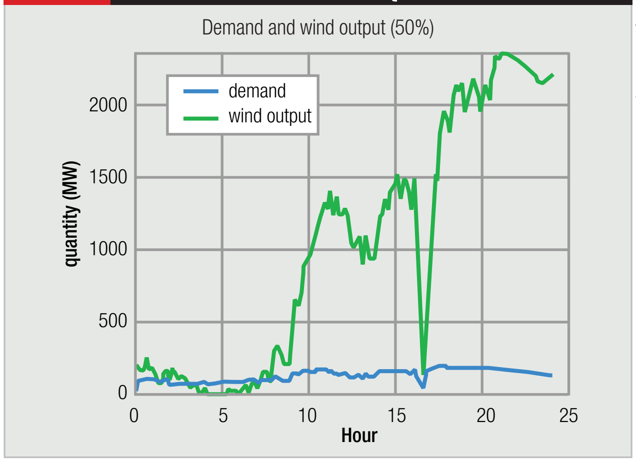
Software in Distributed Risk Management

The implementation of such a simple 3Rs design would go a very long way toward enabling choice by market participants and, at the same time, toward coordinating these choices according to the system-wide performance criteria enforced by the system operators. To ensure that system operators have incentives to deploy the most efficient clearing of bids without creating reliability problems, it's necessary that the system operators be given the incentives to do their job to the best of their ability as well.

For example, reliability-related risks could be managed many different ways and have huge implications on the bids cleared and the overall system cost as well as on environmental pollution. Much monitoring and decision-making know-how by the system operators can be implemented to reduce some very quantifiable system-wide performance metrics without creating reliability problems (*see Reference 6*).

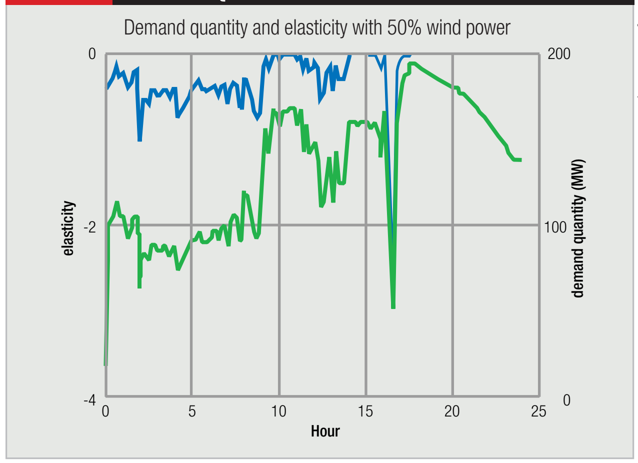
Given the state of the software used today by system operators, the physical risks caused by highly variable resources would be very difficult to untangle and align with financial risks. Instead, an internalizing of the risk by those creating it would make the responsibilities much better understood. It might become possible to establish benchmarks for monitoring the performance of system operators when binding self-commitment is done by the market participants; this has been difficult when the system operators are responsible for managing major uncertainties caused by the highly

Fig. 4 Demand and Wind Power Quantities Scheduled



Source: Carnegie-Mellon University

Fig. 5 Demand Quantity Change and Elasticity Change



Source: Carnegie-Mellon University

variable resources. Allowing renewable resources to vary in highly unpredictable ways, and developing a market in which users are paid for not being served when this occurs, is much harder to implement at present (*see Reference 7*). Instead, risks should be internalized by system users (*e.g.,* power producers, end users and aggregators), and once the bid is made the financial penalty for deviating from the predicted and self-committed bid should be high.[9]

The main reason for designing the 3Rs for effective coordination of variable resources, including responsive demand, is to reduce information rents between the system operators, the portfolios of market participants, and ultimately between the portfolio creators and the individual resources. This can be done only when the self-commitments are binding. Failure to meet the obligation communicated should result in much higher costs to those who deviate from the pre-specified self-commitments. This basic framework could take care of major misalignments and today's lack of incentives. It would begin to compensate the demand adequately for its contribution to the reduced reserves when managing variable wind, for example. This would give incentives to the LSEs to aggregate and reduce volatilities seen by the system. This would be in sharp contrast with what customers are paid today for participating in demand programs by making themselves available for direct load control by the utilities during emergencies. It would incentivize variable resources to reduce the volatilities of their outputs by either making better predictions or installing technologies that can do this, such as storage; otherwise, they would have to pay for the costs borne by the system to manage them as negative loads. Much can be gained by continuous demand response within its constraints even during normal operation. The total cost and pollution will decrease. Customers will be in control of how proactively they wish to participate, and they'd be given signals about how their bills would change. Notably, binding mid-and long-term self-commitments are likely to improve the overall performance much more than very short-term self-commitments (*see Figure 1*).

Much gets accomplished through such self-commitment. Instead of overwhelming the system operators with the requirement to predict system demand, to know in detail ramping rates and start-up and shut-down costs, and to decide on behalf of power producers the risks the latter are willing to take due to uncertainty in prices, these tasks are performed by the power producers themselves. The system operator, instead, is in charge of posting cleared prices and also, even better, forward electricity prices.[10] Similarly, responsive demand internalizes its own physical constraints and the value of the electricity service at various hours, and creates demand functions which are no longer inter-temporally dependent.

Quite importantly, this self commitment leads to risk distribution among all the power producers and customers over time. The system operator no longer takes the major risks of predicting system demand, as this is no longer predictable due to the high variability of resources that aren't directly controlled.

Even more real benefits could be obtained by introducing the 3Rs to medium- and long-term forward markets. A more accurate forecast of the needs and resources available becomes possible only when both power producers and responsive demand provide binding self-commitments. In particular, without utilities and aggregators providing information about longer-term

Fig. 6 Summary Statistics

Price	Spot	1 week	6 weeks
Sample size	574	573	568
Mean	206.1	209.5	216.0
St.Dev.	103.4	109.8	112.2
Max	751.7	877.9	822.5
Min	39.1	46.3	70.0

Spot prices and weekly futures prices with one week and six weeks to delivery, 1996-2006.

Source: Botterud, Kristiansen Marija Ilic, *see Reference 9* demand characteristics, much would be built in an open-loop manner resulting in gross under-utilization. Instead, fairly straightforward 3Rs for mid-and long-term forward markets should be designed to present symmetric risks to all parties. This probably is the only sustainable way toward efficient utilization and investments in future energy systems.

To make the point clear about the relevance of mid-and long-term forward electricity markets with transparent and binding 3Rs, it's helpful to look into the major discrepancy between the expected price based on historic spot prices and the actual forward prices in NordPool where such prices are publicly posted (*see Reference 9 and Figures 2 and 3*).

The further into the future one goes, the higher are the deviations from the expected mean and the higher the variance (*see Figure 6*). Both the deviations from the expected mean and the variance are very significant and have a major impact on the prices of electricity and signals for right investments. Without the right mid- and long-term 3Rs, these risks are very asymmetric and create tremendous volatilities in spot markets, and longer term imbalances between the supply and demand (*see Reference 10*). To align risks in electricity markets with risks in fuel markets and cap and trade markets, it's essential and long overdue to have 3Rs for mid- and long-term electricity forward markets (*see References 10 and 11*).

Last but not least, T&D investments, although fully regulated, could become more used and useful if the longer-term forward signals about likely demand and supply are made more transparent. The predictions must be binding; otherwise they remain useless. The presence of binding mid- and long-term self-commitments would help tremendously in allocating mid- and long-term financial transmission rights (FTRs) which reflect the inter-dependence of physical and financial risks.

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And of course, load can't be kept perfectly at what is committed, and neither can wind be predicted perfectly. But what can be done by each self-committing participant is to provide statistical bounds within which deviations can occur away from the predictable self-committed specifications. These simply can't be determined by system operators, but it's information perfectly within the abilities of market participants who know their own equipment over almost any time horizon.

It will become necessary to create some other derivatives, once the basic 3Rs are in place, to manage hard-to-predict uncertainties. It is critical to note that these uncertainties are an order of magnitude smaller with binding self-commitments than without (*see Reference 8 and Figure 4*).

Aligning Incentives

Streamlining effective wind integration will require taking a serious look at today's operating and planning practices by regulated utilities, as well as at the 3Rs for the electricity markets. Given the high variability of wind and demand willing to participate, the related regulatory, physical, financial risks and information rents must be *(Cont. on p. 67)*

they view it as unstable and disruptive. They need reliability and performance, along with an interconnect that lets them on-board the power in a comfortable manner. That's what this system provides."

Indeed, with solar plants becoming vastly larger than they once were, utilities require much greater ability to manage and control their output. Not long ago, a 1-MW PV facility was considered a major technological achievement. Now Chicago-based Exelon is building an 10-MW facility on the city's south side; FP&L owns and operates the 25 MW DeRosa facility; SCE and PGE are each looking to develop and own some 250 MW of PV over the next five years; and CSP developers are looking to add thousands of megawatts in new capacity to the nation's grid (*see Figure 1*).

So solar certainly is on a roll, but much work remains to be done.

> "Solar makes a lot of sense, but utilities are used to dealing with rotating equipment and this is a whole new animal."
>
> *– Ryan Sather, Accenture*

"I was recently on a plane sitting next to this investment banker type who's telling me about a solar project his firm had gotten involved in somewhere in the Southwest," says Ryan Sather, senior manager of generation and energy markets for global business consultant Accenture. "He said the one area they failed to consider was the cost of keeping the mirrors clean. They hadn't anticipated the dust and the annual cost of having to clean it. It wasn't part of the financial model and that tripped them up."

From an electric utility standpoint, Sather's story is an apt metaphor. While there's plenty of optimism, there's still plenty to prove—and the industry is bound to make mistakes.

"Solar makes a lot of sense in certain parts of California and the Southwest," Sather says. "But utilities are used to dealing with rotating equipment and this is a whole new animal. A lot of questions still need to answered. How big does the plant have to be? What's a cost-effective capacity rating? How will solar impact grid operations? And what are the O&M costs?"

The current crop of plants might provide some answers, giving utilities the technology experience they need to make the most of solar energy's expanding future.

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supported by the right 3Rs. Otherwise, the incentives remain misaligned with the potential values brought about by new technologies.

A well-defined self-commitment by future resources is key to the clean and cost-effective use of wind and responsive demand. The implementation of self-commitment would require a transformation of today's SCADA systems into multi-directional, multi-layered interactive dynamic monitoring and decision systems (DYMONDS). However, if this is done systematically, at least the first generation DYMONDS would be a natural outgrowth of today's SCADA, and wouldn't require a major re-design. Today's SCADA would have to be enhanced by interactive multi-directional information exchange between system operators, aggregators of variable resources (such as wind, solar and demand) and the resources themselves. The NIST standards and protocols under design must enable minimal information exchange from the system operators to the aggregators and resources, in both directions and multilaterally. An IEEE test system has shown that this system is capable of integrating greater than 50 percent wind capacity with less than 3 percent demand elasticity during most hours, while observing the same transmission limits. Symmetric distributed risk management is beneficial for all industry participants as their value is aligned with what they are compensated for.

Endnotes:

1. Systems with large storage wouldn't be as dependent on near-real time knowledge. Without storage, the large stand-by reserve is used. The first solution is still in the embryonic stages, and the second solution leads to under-utilization and inefficiency.
2. Customers could and should contribute to making utilization of clean renewable power feasible, but need to be compensated for this. On the other hand, they would be required to provide the information to their load-serving entities about their short- and long-term needs and willingness to respond to system conditions and the price at which they would do this. It's a misconception that only real-time price response is key to the efficient utilization. Instead, good information about longer time-of-use patterns is essential for long-term efficient and reliable investments at the price customers are willing to pay.
3. Today's automatic generation control (AGC) is implemented because it's impossible to predict system load deviations in between the times when the dispatch is done. The same will remain true with the new resources. Assuming that the deviations are poorly predicted, the need for AGC reserve and voltage support-related reserve would escalate and the price in this market would become very high. This cost must be borne by those creating the deviations, and the technologies capable of participating in this market would begin to recover their costs at the value they bring to the system based on the charges from those

who create the need for these technologies.

4. Load serving entities (LSEs) will play a major role in creating such portfolios of customers and users, including the addition of storage, PHEVs, wind power, and other resources.
5. These are fundamentally different from the forward prices posted by the financial bilateral trading now required in FERC 719. System operators remain key to clearing these long-term bilateral contracts given the physical power grid constraints—congestion in particular.
6. Social welfare is the sum of customer benefits minus the cost borne by the suppliers, subject to transmission congestion constraints.
7. It's assumed here that demand is fully responsive. Any other response can be used. Generally, results will depend on the relative rates of response of different power plants and the responsive demand.
8. Demand elasticity is the ratio of percentage change demand quantity and percentage change of unit price.
9. In case some resources aren't capable of providing their self-commitments with very high confidence, they should be required to provide bounds within which they are likely to deviate. This information will be essential for committing resources to so-called ancillary services and will result in higher charges to the system users. The design of such an ancillary market is technologically possible as well (*see Reference 8*) but, since it requires very fast-responding technologies, to manage it should have much higher clearing prices than the forward energy market prices, if done right. It will be very difficult to justify expensive storage for balancing predictable changes. Their main value comes from managing hard-to-predict deviations from self-commitments and their cost should be recoverable to a large extent by participating in the ancillary services where their value is the highest. It's important to keep in mind that aggregators play a major role in packaging highly volatile resources as one better predictable bid.
10. At present in the United States there is very little transparency in forward electricity markets. In the Australian market as well as in the NordPool market the forward market is functional and this significantly reduces price volatility in short-term day- and hour-ahead markets.

Negawatt Pricing

(Cont. from p. 27)

and the capacity savings that wouldn't occur until past 2010, and states in any event that the gains enjoyed by non-curtailing customers due to market-wide energy price reductions always will prove short-lived, since they can exist only when generating capacity is in surplus—as in PJM in 2005—and will be given back once demand growth absorbs the surplus and new generation is needed, thus driving capacity prices back up. However, Borlick's most telling indictment of DR incentive payments concerns the possibility of market price manipulation.

Proponents often tout DR as the best method to counterbalance supplier market power, which arises when power producers can benefit by withholding a portion of production from the market, so as to boost prices captured by remaining capacity. But as Borlick points out, PJM's DR incentive proposal might well be tried for the same charge: "PJM is proposing to make 'incentive payments' to DR providers in order to drive down spot market prices, so that the loads remaining in the market derive greater value." (*See, Protest of Robert L. Borlick, FERC Docket EL09-68, Sept. 16, 2009.*)

In effect, as Borlick concludes, "PJM is proposing to use its unique position … to manipulate market prices in a way that benefits one class of market participants (load-serving entities and their retail customers) at the expense of another class of market participants (suppliers).

"When this is done with the explicit intent of optimizing the net gains from changes in market prices, we are in the realm of collusive behavior."

Subsidy, Schmubsidy

Eric Woychik, v.p of regulatory affairs for Comverge, offers perhaps the best argument for paying an incentive or subsidy to DR providers—that the sheer complexity of state-approved retail rate designs makes it much too difficult for curtailing customers to calculate the dollar amount of the avoided retail energy charge, in order to net out the true value of *LMP – G*, and so puts load at a disadvantage as against generation suppliers, who can log on to the Internet and get an instantaneous, minute-to-minute readout of LMP prices, to guide their decisions on how to bid their supply into the market.

Indeed, state utility commissions aren't uniform in their choices of rate designs. Sometimes fixed costs are recovered through the energy charge, or variable costs are recovered through the demand charge. Decoupling efforts by some state PUCs further complicate the task of calculating the avoided energy charge (G) and thus put in doubt the exact dollar payoff for the would-be DR provider.

"The deck is stacked against customer and DR providers," notes Woychik, testifying on behalf of the Demand Response Supporters. "Many customers and DR providers that would otherwise participate in the market cannot easily translate the existing and proposed PJM economic compensation policies [such as *LMP – G*] into day-to-day operational rules.

"These net-pricing results are lagged and resolved with certainty only after the PJM settlement period is over."

Imagine the difficulty faced by a large-scale industrial facility, as described in testimony given by Ron Belbot, of the Severstal Sparrows Point steel plant in Baltimore, explaining how the plant managers decide on whether to submit a DR bid: "When loads are forecast to be high, with correspondingly high LMPs, the operation of each of the facilities is reviewed … Information like where a unit is in a particular production run, and if that run can be interrupted without affecting quality or damaging equipment … If a product is being produced »